

Table 39. PEAK BENEFITS BY SEASON: AVERAGE PRICES COMPARED WITH PEAK PRICES WHICH DECREASE PEAK KWH TEN PERCENT AND WITH LRMC

Duke Power Company, 1972

Rate Schedule by Season	Long Run Average Price Elasticity  /ε <sub>av</sub> /	Present Average Price, P <sub>av</sub> \$/KWH	Price Change Consist. with a 10% Decrease in Peak KWH, ΔP <sub>10</sub> \$/KWH	LRMC if 1/2LRMC<P <sub>av</sub> Otherwise 1/2LRMC \$/KWH	Peak KWH in Season, KWH pk 10 <sup>6</sup> KWH	Efficiency Gains Associated With a Ten Percent Decrease in Peak KWH		Efficiency Gain Associated with Upper Bound or One-Half Upper Bound				
						Frac- tional Price Change ΔP <sub>10</sub> / P <sub>av</sub> x.1	Efficiency Gains ΔKWH = 1/2ε <sub>av</sub> ΔP <sub>10</sub> KWH <sub>pk</sub> ΔP <sub>10</sub> / P <sub>av</sub>	Price Change at Peak, ΔP <sub>pk</sub> - LRMC-P <sub>av</sub> if 1/2LRMC<P <sub>av</sub> , Otherwise	Average Frac- tional Price Change ΔP <sub>pk</sub> / P <sub>av</sub>	Efficiency Gains ΔW <sub>pk</sub> = 1/2ε <sub>av</sub> ΔP <sub>pk</sub> KWH <sub>pk</sub> ΔP <sub>pk</sub> / P <sub>av</sub>	Change in Peak KWH ΔKWH <sub>pk</sub> 10 <sup>6</sup> KWH	Percentage Change in Peak KWH
	1	2	3	4	5	6	7	8	9	10	11	12
Residential (R)												
July-October	1.18	.0265	.0022	325	279,346	.0847	30,711	.0060	.203	201,129	- 67,043	- 24.0
November-February	1.18	.0265	.0022	317	270,234	.0847	29,710	.0052	.179	125,767	- 48,372	- 21.1
March-June	1.18	.0265	.0022	327	225,059	.0847	24,743	.0062	.209	172,329	- 55,590	- 24.7
Residential (RA)												
July-October	1.18	.0167	.0014	270 <sup>a</sup>	578,645	.0847	40,483	.0103	.471	1,656,894	- 321,727	- 55.6
November-February	1.18	.0167	.0014	266 <sup>a</sup>	559,769	.0847	39,163	.0099	.457	1,495,489	- 301,715	- 53.9
March-June	1.18	.0167	.0014	272 <sup>a</sup>	466,193	.0847	30,307	.0105	.478	1,380,398	- 262,933	- 56.4
Residential (RW)												
July-October	1.18	.0201	.0017	205 <sup>a</sup>	1,010,966	.0847	85,886	.0004	.020	4,853	- 24,263	- 2.4
November-February	1.18	.0201	.0017	201 <sup>a</sup>	977,988	.0847	83,084	.00	.00	0	- 00	0
March-June	1.18	.0201	.0017	207 <sup>a</sup>	814,499	.0847	69,195	.0006	.029	8,308	- 27,693	- 3.4
Residential (WGS & Misc)												
July-October	1.18	.0155	.0013	309 <sup>a</sup>	13,302	.0847	864	.0154	.664	80,303	- 10,429	- 78.4
November-February	1.18	.0155	.0013	304 <sup>a</sup>	12,868	.0847	836	.0149	.649	73,338	- 9,844	- 76.5
March-June	1.18	.0155	.0013	313 <sup>a</sup>	10,717	.0847	696	.0158	.675	67,474	- 8,541	- 79.7
Commercial and Industrial (C)												
July-October	1.13	.0168	.0015	205 <sup>a</sup>	891,246	.0885	66,847	.0037	.198	367,682	- 195,747	- 22.3
November-February	1.13	.0168	.0015	202 <sup>a</sup>	862,173	.0885	64,666	.0034	.184	312,193	- 183,613	- 21.3
March-June	1.13	.0168	.0015	208 <sup>a</sup>	718,045	.0885	53,856	.0040	.213	346,098	- 173,049	- 24.1
Commercial and Industrial (CA)												
July-October	1.13	.0112	.0010	143 <sup>a</sup>	548,715	.0885	27,437	.0031	.243	233,890	- 150,897	- 27.5
November-February	1.13	.0112	.0010	142 <sup>a</sup>	530,816	.0885	26,542	.0030	.236	212,592	- 141,728	- 26.7
March-June	1.13	.0112	.0010	146 <sup>a</sup>	442,080	.0885	22,105	.0034	.263	223,207	- 131,296	- 29.7
Commercial and Industrial (CI)												
July-October	1.65	.0089	.0005	137 <sup>a</sup>	1,402,182	.0606	35,051	.0048	.425	2,350,032	- 982,930	- 70.1
November-February	1.65	.0089	.0005	136 <sup>a</sup>	1,402,182	.0606	35,051	.0047	.418	2,273,639	- 967,506	- 69.0
March-June	1.65	.0089	.0005	140 <sup>a</sup>	1,402,182	.0606	35,051	.0051	.445	2,625,643	- 1,029,664	- 73.4
Commercial and Industrial (IRES)												
July-October	1.65	.0079	.0005	135 <sup>a</sup>	73,954	.0606	1,849	.0056	.523	178,702	- 63,822	- 86.3
November-February	1.65	.0079	.0005	134 <sup>a</sup>	73,954	.0606	1,849	.0055	.516	178,821	- 62,955	- 85.1
March-June	1.65	.0079	.0005	138 <sup>a</sup>	73,954	.0606	1,849	.0059	.544	195,912	- 66,411	- 89.8
Commercial and Industrial (All Others)												
July-October	1.65	.0278	.0017	410 <sup>a</sup>	29,512	.0606	2,509	.0132	.384	123,493	- 18,711	- 63.4
November-February	1.65	.0278	.0017	409 <sup>a</sup>	29,512	.0606	2,509	.0131	.381	121,588	- 18,563	- 62.9
March-June	1.65	.0278	.0017	413 <sup>a</sup>	29,512	.0606	2,509	.0135	.391	128,486	- 19,035	- 64.5
Other Public Authorities												
July-October	1.65	.0105	.0006	141 <sup>a</sup>	18,347	.0606	550	.0036	.293	15,917	- 8,845	- 48.2
November-February	1.65	.0105	.0006	140 <sup>a</sup>	18,347	.0606	550	.0035	.286	15,155	- 8,600	- 47.2
March-June	1.65	.0105	.0006	144 <sup>a</sup>	18,347	.0606	550	.0039	.313	18,461	- 9,467	- 51.6
Sales for Resale												
July-October	1.65	.0089	.0005	191 <sup>a</sup>	510,830	.0606	12,769	.0107	.751	3,386,111	- 632,918	- 123.9
November-February	1.65	.0089	.0005	193 <sup>a</sup>	510,830	.0606	12,769	.0106	.746	3,332,810	- 628,832	- 123.1
March-June	1.65	.0089	.0005	192 <sup>a</sup>	510,830	.0606	12,769	.0110	.764	3,542,863	- 644,157	- 126.1
Interdepartmental												
July-October	1.65	.0144	.0009	135 <sup>a</sup>	461	.0606	21	.0009	.065	22	- 49	- 10.7
November-February	1.65	.0144	.0009	134 <sup>a</sup>	461	.0606	21	.0010	.071	27	- 54	- 11.7
March-June	1.65	.0144	.0009	138 <sup>a</sup>	461	.0606	21	.0006	.043	32	- 32	- 7.1
					215,327,744		2855,378			225,456,636	2-7,280,101	- 47.5

Table 40. PEAK BENEFITS BY SEASON: AVERAGE PRICES COMPARED WITH PEAK PRICES WHICH DECREASE PEAK KWH TEN PERCENT AND WITH LRMC

New York State Electric and Gas, 1972

Rate Schedule by Season	Long Run Average Price Elasticity $\epsilon_{av}$	Present Average Price, $P_{av}$ \$/KWH	Price Change Consistent with a 10% Decrease in Peak KWH, $\Delta P_{10}$ \$/KWH	LRMC if $\frac{1}{2} \times LRMC < P_{av}$ , Otherwise $\frac{1}{2} \times LRMC$ \$/KWH	Peak KWH in Season, $KWH_{pk}$ $10^3 KWH$	Efficiency Gains Associated With a Ten Percent Decrease In Peak KWH		Efficiency Gain Associated with Upper Bound or One-Half Upper Bound				
						Fractional Price Change $\frac{\Delta P_{10}}{P_{av}} = \frac{1}{\epsilon_{av}} \times 1$	Efficiency Gains $\Delta W_{10} = \frac{1}{2} \epsilon_{av} \Delta P_{10} KWH_{pk}$	Price Change at Peak, $\Delta P_{pk}$ LRMC - $P_{av}$ if $\frac{1}{2} LRMC < P_{av}$ , Otherwise $\frac{1}{2} LRMC - P_{av}$	Average Fractional Price Change $\frac{\Delta W_{pk}}{KWH_{pk}}$	Efficiency Gains $\Delta W_{pk} = \frac{1}{2} \epsilon_{av} \Delta P_{pk} KWH_{pk}$	Change in Peak KWH $\Delta KWH_{pk}$ $10^3 KWH$	Percentage Change in Peak KWH
	1	2	3	4	5	6	7	8	9	10	11	12
Residential												
November-February	1.24	.0272	.0022	.0330	574,163	.0806	63,123	.0058	.193	397,952	- 137,225	- 23.9
March-June	1.24	.0272	.0022	.0328	471,407	.0806	54,826	.0056	.187	306,226	- 109,366	- 23.2
July-October	1.24	.0272	.0022	.0328	497,435	.0806	54,687	.0056	.187	325,131	- 115,405	- 23.2
General Service (SC2 PSC 113)												
November-February	1.65	.0273	.0017	.0333 <sup>a</sup>	147,458	.0606	12,533	.0060	.198	144,654	- 48,218	- 32.7
March-June	1.65	.0273	.0017	.0333 <sup>a</sup>	120,931	.0606	10,278	.0060	.198	118,632	- 39,544	- 32.7
July-October	1.65	.0273	.0017	.0333 <sup>a</sup>	127,991	.0606	10,878	.0060	.198	125,559	- 41,855	- 32.7
General Service (SC2 PSC 108)												
November-February	1.65	.0175	.0011	.0227 <sup>a</sup>	86,342	.0606	4,748	.0052	.259	95,857	- 36,868	- 42.7
March-June	1.65	.0175	.0011	.0229 <sup>a</sup>	71,023	.0606	3,906	.0054	.267	84,567	- 31,321	- 44.1
July-October	1.65	.0175	.0011	.0229 <sup>a</sup>	74,944	.0606	4,122	.0054	.267	89,236	- 33,050	- 44.1
Large Light and Power (SC3 PSC 113)												
November-February	1.89	.0138	.0007	.0178 <sup>a</sup>	191,910	.0529	6,716	.0040	.253	183,466	- 91,733	- 47.8
March-June	1.89	.0138	.0007	.0181 <sup>a</sup>	191,910	.0529	6,716	.0043	.270	210,429	- 97,874	- 51.0
July-October	1.89	.0138	.0007	.0180 <sup>a</sup>	191,910	.0529	6,716	.0042	.264	201,102	- 95,765	- 49.9
Primary Light and Power (SC3 PSC 108)												
November-February	1.89	.0103	.0005	.0176 <sup>a</sup>	33,310	.0529	833	.0073	.523	120,123	- 32,810	- 98.8
March-June	1.89	.0103	.0005	.0179 <sup>a</sup>	33,310	.0529	833	.0076	.539	128,983	- 33,843	- 101.9
July-October	1.89	.0103	.0005	.0178 <sup>a</sup>	33,310	.0529	833	.0075	.534	126,037	- 33,610	- 100.9
Other Public Authority												
November-February	1.89	.0169	.0009	.0219	73,055	.0529	3,287	.0050	.305	105,199	- 42,080	- 57.6
March-June	1.89	.0169	.0009	.0222	73,055	.0529	3,287	.0053	.272	100,476	- 37,915	- 51.4
July-October	1.89	.0169	.0009	.0221	73,055	.0529	3,287	.0052	.267	95,921	- 36,693	- 50.5
Interchange and Resale												
November-February	1.89	.0080	.0004	.0145	95,913	.0529	1,918	.0065	.578	340,595	- 104,737	- 109.2
March-June	1.89	.0080	.0004	.0146	95,913	.0529	1,918	.0066	.584	349,430	- 105,888	- 110.4
July-October	1.89	.0080	.0004	.0146	95,913	.0529	1,918	.0066	.584	349,430	- 105,888	- 110.4
					23,354,258		2254,362			23,996,805	2-1,412,084	- 42.1

<sup>a</sup>Full upper bound

Table 41. PEAK BENEFITS BY SEASON: AVERAGE PRICES COMPARED WITH PEAK PRICES WHICH DECREASE PEAK KWH TEN PERCENT AND WITH LRMC

Pennsylvania Power and Light Company, 1972

Rate Schedule by Season	Long Run Average Price Elasticity $\epsilon_{av}$	Present Average Price, $P_{av}$ \$/KWH	Price Change Consis. with a 10% Decrease in Peak KWH, $\Delta P_{pk}$ \$/KWH	LRMC if $\frac{1}{2} \times LRMC < P_{av}$ Otherwise $\frac{1}{2} \times LRMC$ \$/KWH	Peak KWH in Season, $KWH_{pk}$ $10^3$ KWH	Efficiency Gains Associated With a Ten Percent Decrease in Peak KWH		Efficiency Gain Associated with Upper Bound or One-Half Upper Bound				
						Fractional Price Change $\frac{\Delta P_{pk}}{P_{av}}$	Efficiency Gains $\Delta W_{pk}$	Price Change at Peak, $\Delta P_{pk}$	Average Fractional Price Change	Efficiency Gains $\Delta W_{pk}$	Change in Peak KWH $\Delta KWH_{pk}$ $10^3$ KWH	Percentage Change in Peak KWH
						$\frac{1}{\epsilon_{av}} \times \frac{1}{2}$	$\frac{1}{2} \epsilon_{av} \Delta P_{pk} KWH_{pk}$	LRMC $< P_{av}$ if $\frac{1}{2} LRMC < P_{av}$ Otherwise				
	1	2	3	4	5	6	7	8	9	10	11	12
Residential (RS)												
November-February	1.22	.0271	.0022	.0370	724,801	.0820	79,760	.0099	.308	1,348,139	- 272,351	- 37.6
March-June	1.22	.0271	.0022	.0381	568,600	.0820	62,571	.0110	.337	1,285,758	- 233,774	- 41.1
July-October	1.22	.0271	.0022	.0312	582,477	.0820	64,098	.0041	.141	205,405	- 100,197	- 17.2
Residential (RH)												
November-February	1.22	.0171	.0014	.0318 <sup>a</sup>	361,167	.0820	25,291	.0147	.601	1,946,389	- 264,814	- 73.3
March-June	1.22	.0171	.0014	.0328 <sup>a</sup>	283,332	.0820	19,841	.0157	.629	1,706,773	- 217,423	- 76.7
July-October	1.22	.0171	.0014	.0272 <sup>a</sup>	290,247	.0820	20,325	.0101	.456	815,425	- 161,470	- 55.6
Residential (SGS, AZ, and GS)												
November-February	1.22	.0673	.0055	.0277 <sup>a</sup>	2,138	.0820	588	.0396	-.834	43,072	+ 2,175	+ 1.017
March-June	1.22	.0673	.0055	.0285 <sup>a</sup>	1,667	.0820	458	.0388	-.810	31,958	+ 1,647	+ 98.8
July-October	1.22	.0673	.0055	.0258 <sup>a</sup>	1,718	.0820	472	.0435	-.955	43,536	+ 2,001	+ 1.165
Commercial and Industrial (SGS)												
November-February	1.46	.0426	.0029	.0597 <sup>a</sup>	116,606	.0685	12,343	.0171	.334	486,168	- 56,861	- 48.8
March-June	1.46	.0426	.0029	.0617 <sup>a</sup>	91,447	.0685	13,261	.0191	.366	466,667	- 48,865	- 53.4
July-October	1.46	.0426	.0029	.0489 <sup>a</sup>	93,709	.0685	13,589	.0063	.138	59,474	- 18,830	- 20.1
Commercial and Industrial (LP3)												
November-February	1.46	.0231	.0016	.0219 <sup>a</sup>	439,947	.0685	35,199	.0012	-.053	20,426	+ 34,043	+ 7.7
March-June	1.46	.0231	.0016	.0227 <sup>a</sup>	345,134	.0685	27,627	.0004	-.035	3,527	+ 17,636	+ 5.1
July-October	1.46	.0231	.0016	.0195 <sup>a</sup>	353,557	.0685	28,287	.0036	-.169	157,026	+ 87,236	+ 2.5
Commercial and Industrial (LP4)												
November-February	1.93	.0153	.0008	.0210 <sup>a</sup>	160,438	.0518	6,415	.0057	.314	277,102	- 97,228	- 60.6
March-June	1.93	.0153	.0008	.0216 <sup>a</sup>	160,438	.0518	6,415	.0063	.341	344,669	- 105,589	- 65.8
July-October	1.93	.0153	.0008	.0187 <sup>a</sup>	160,438	.0518	6,415	.0034	.200	105,279	- 61,929	- 38.6
Commercial and Industrial (LP5)												
November-February	1.93	.0128	.0007	.0211 <sup>a</sup>	81,890	.0518	2,865	.0083	.490	321,390	- 77,468	- 94.6
March-June	1.93	.0128	.0007	.0217 <sup>a</sup>	81,890	.0518	2,865	.0088	.516	326,009	- 81,562	- 98.6
July-October	1.93	.0128	.0007	.0188 <sup>a</sup>	81,890	.0518	2,865	.0060	.380	180,174	- 60,025	- 73.3
Commercial and Industrial (LP6)												
November-February	1.93	.0128	.0007	.0209 <sup>a</sup>	188,779	.0518	6,605	.0081	.481	684,918	- 175,249	- 92.8
March-June	1.93	.0128	.0007	.0215 <sup>a</sup>	188,779	.0518	6,605	.0087	.507	803,541	- 184,722	- 97.8
July-October	1.93	.0128	.0007	.0186 <sup>a</sup>	188,779	.0518	6,605	.0058	.369	389,884	- 134,442	- 71.2
Commercial and Industrial (LP)												
November-February	1.93	.0128	.0007	.0219 <sup>a</sup>	44,302	.0518	1,550	.0091	.524	203,856	- 44,789	- 101.1
March-June	1.93	.0128	.0007	.0225 <sup>a</sup>	44,302	.0518	1,550	.0097	.550	228,079	- 47,004	- 106.1
July-October	1.93	.0128	.0007	.0196 <sup>a</sup>	44,302	.0518	1,550	.0068	.420	122,098	- 35,929	- 81.1
Commercial and Industrial (NS)												
November-February	1.93	.0166	.0009	.0222 <sup>a</sup>	70,321	.0518	3,163	.0056	.289	109,824	- 39,222	- 55.8
March-June	1.93	.0166	.0009	.0228 <sup>a</sup>	70,321	.0518	3,163	.0062	.315	132,530	- 42,751	- 60.8
July-October	1.93	.0166	.0009	.0199 <sup>a</sup>	70,321	.0518	3,163	.0033	.181	40,533	- 24,565	- 34.9
Commercial and Industrial (BST)												
November-February	1.93	.0166	.0009	.0209 <sup>a</sup>	43,036	.0518	1,936	.0043	.220	40,901	- 10,022	- 22.2

Table 41 (Continued) PEAK BENEFITS BY SEASON: AVERAGE PRICES COMPARED  
WITH PEAK PRICES WHICH DECREASE PEAK KWH TEN PERCENT AND WITH LRMC

Pennsylvania Power and Light Company, 1972

Rate Schedule by Season	Long Run Average Price Elasticity $\epsilon_{av}$	Present Average Price, $P_{av}$ \$/KWH	Price Change Consis. with a 10 % Decrease in Peak KWH, $\Delta P_{10}$ \$/KWH	LRMC if $\frac{1}{2} \times LRMC < P_{av}$ Otherwise $\frac{1}{2} \times LRMC$ \$/KWH	Peak KWH in Season, KWH $10^3$ KWH $pk$	Efficiency Gains Associated With a Ten Percent Decrease In Peak KWH		Efficiency Gain Associated with Upper Bound or One-Half Upper Bound				
						Frac- tional Price Change $\frac{\Delta P_{10}}{P_{av}} =$ $\frac{1}{\epsilon_{av}} \times .1$	Efficiency Gains $\Delta W_{10} =$ $\frac{1}{2} \epsilon_{av} \Delta P_{10} KWH_{pk}$	Price Change at Peak, $\Delta P_{pk}$ LRMC - $P_{av}$ if $\frac{1}{2} LRMC < P_{av}$ Otherwise $\frac{1}{2} LRMC - P_{av}$	Average Frac- tional Price Change	Efficiency Gains $\Delta W_{pk} =$ $\frac{1}{2} \epsilon_{av} \Delta P_{pk} KWH_{pk}$	Change in Peak KWH $\Delta KWH_{pk}$ $10^3$ KWH	Percentage Change in Peak KWH
Commercial and Industrial (All Other)												
November-February	1.93	.0092	.0005	.0166	51,917	.0518	1,297	.0074	.574	194,267	- 52,488	- 1.011
March-June	1.93	.0092	.0005	.0169	51,917	.0518	1,297	.0077	.590	227,604	- 59,133	- 1.139
July-October	1.93	.0092	.0005	.0155	51,917	.0518	1,297	.0063	.510	160,971	- 51,086	- .98.4
Other Public Authorities												
November-February	1.93	.0691	.0036	.0209 <sup>a</sup>	54	.0518	9	.0482	-1.071	2,690	+ 112	+206.7
March-June	1.93	.0691	.0036	.0215 <sup>a</sup>	54	.0518	9	.0476	-1.051	2,607	+ 109	+202.8
July-October	1.93	.0691	.0036	.0186 <sup>a</sup>	54	.0518	9	.0505	-1.152	3,032	+ 120	+222.3
Railroads and Railways												
November-February	1.93	.0223	.0012	.0209 <sup>a</sup>	12,862	.0518	772	.0014	-.065	1,129	+ 1,607	+ 12.5
March-June	1.93	.0223	.0012	.0215 <sup>a</sup>	12,862	.0518	772	.0008	-.037	367	+ 9,193	+ 71.4
July-October	1.93	.0223	.0012	.0186 <sup>a</sup>	12,862	.0518	772	.0037	-.181	8,312	+ 4,488	+ 34.9
Interdepartmental												
November-February	1.93	.0111	.0006	.0209 <sup>a</sup>	254	.0518	8	.0098	.613	1,472	- 300	-118.3
March-June	1.93	.0111	.0006	.0215 <sup>a</sup>	254	.0518	8	.0104	.638	1,626	- 313	-123.1
July-October	1.93	.0111	.0006	.0186 <sup>a</sup>	254	.0518	8	.0075	.505	928	- 248	- 97.5
Interchange and Resale												
November-February	1.93	.0110	.0006	.0135	220,131	.0518	6,602	.0025	.204	108,337	- 86,731	- 39.4
March-June	1.93	.0110	.0006	.0138	220,131	.0518	6,602	.0028	.226	134,423	- 95,977	- 43.6
July-October	1.93	.0110	.0006	.0124	220,131	.0518	6,602	.0014	.120	35,688	- 51,070	- 23.2
					26,878,600		2497,376			213,912,252	2-2,875,374	- 41.8

<sup>a</sup> Full upper bound

Turning to the task of estimating the incremental cost of double register metering of residential customers, an example will serve to illustrate the procedure. From the Sangamo Electric Company we have obtained acquisition cost figures for the ordinary, or single register, KWH meter and for the double register meter which would be necessary if residential customers were to be charged different prices offpeak and on peak. The simpler meter could be acquired by utilities for \$16.00 in 1972, and the double register meter for \$57.58. But it would be incorrect to take these as capital cost figures, for the capital cost of a meter which is entered into a utility's rate base is the installation cost of the meter, and installation cost can be substantial and varies between companies. From Federal Power Commission Form 1 we can 'reconstruct each system's installation costs by the simple expedient of deducting from the reported per meter increase in the rate base our known acquisition cost of \$16. For example, for the Potomac Electric Power Company 1972 installation cost computed thus is \$56.51. Assuming that installation costs for the double rate register are not higher than those for the single rate register, we may add this installation cost figure to the acquisition cost figure for the double rate register, \$57.58, in order to obtain a capital cost figure for double register metering, in this case \$114.09. Of course, the single register figure, obtained directly from Form 1, is \$72.51. By annualizing each of these capital cost figures--as above, we assume an 8 percent rate of return on original cost--we have annual capital cost figures for single and double rate registers. For operating and maintenance cost estimates, we have available the breakdown provided by Form 1 in which operating costs are composed into meter reading costs, meter maintenance costs and a miscellaneous meter expenses category. The definition of meter expenses given in the Federal Power Commission's

standard accounts is the obvious one; while meter expenses "shall include the cost of labor, materials and expenses used and incurred in the operation of customer meters and associated equipment," i.e., operating as opposed to maintenance expenses associated with metering, exclusive of meter reading expenses.

Since we have, for each system, the number of meters, each of these figures can be put on a per meter basis. For example, in 1972 the Potomac Electric Power Company reported per meter reading expenses of \$2.11, per meter maintenance expenses of \$.33, and per meter meter expenses of \$1.65, or total per meter operating and maintenance expenses of \$4.09. In our estimates of the corresponding figures for double register metering, we have somewhat naively assumed, for each system, the same numbers. This is certainly defensible for meter reading: the major expense is the labor and transportation cost involved in moving the reader between meters. For the remaining components of operating and maintenance cost, the assumption is not as persuasive, but we have no alternative. The cost differential between single register and double register metering is then equal to the difference between annualized capital cost figures for the two modes of monitoring, and it is this differential that is entered as the column "Incremental Cost of Metering per Customer" in Table 42, Net Peak Period Residential Schedule Indicators of Improved Pricing. By multiplying that figure by the average number of customers served during 1972 under each residential rate schedule for each of our systems, and deducting the product from our previous estimates for these schedules in Tables 37 through 41--remember that there are two such figures, one for a price change which depresses peak consumption by 10 percent, and another for a price change in which our upper bounds are used as prices--we obtain the net benefit or indicator figures of the final two columns of Table 42.

Table 42. NET PEAK PERIOD RESIDENTIAL, SCHEDULE INDICATORS OF IMPROVED PRICING

System Rate Schedule	1	2	3	4	5	6	7
	Ten Percent Peak Benefits -Gross Benefits (\$)	Peak Upper Bound -Gross Benefits (\$)	Average Number of Customers	Incre- mental Metering Cost per Customer (\$)	Total Incremental Metering Cost (\$)	Net Benefits I = 1 - 5 (\$)	Net Benefits II = 2 - 5 (\$)
POTOMAC ELECTRIC POWER COMPANY Residential	137,610	5,548,191	391,046	4.48	1,751,886	-1,614,276	3,796,305
COMMONWEALTH EDISON COMPANY Small Residential	156,775	10,251,715	1,003,359	4.84	4,856,257	-4,699,482	3,830,542
Large Residential	719,558	60,741,870	1,348,632		6,527,379	-5,807,821	54,214,491
Residential Space Heating	19,515	20,934	62,894		304,407	- 284,892	-9,473
DUKE POWER COMPANY Residential (R)	85,164	499,225	253,559	4.56	1,156,229	-1,071,065	-657,004
Residential (RS)	109,953	4,530,781	138,189		630,141	- 520,188	-13,906,640
Residential (RW)	235,165	13,161	488,754		2,228,718	-1,993,553	-2,215,557
Residential (WGS & MISC)	2,396	221,115	3,657		16,676		
NEW YORK ELECTRIC AND GAS Residential	169,635	1,027,309	525,616	4.65	2,444,114	-2,274,479	-1,416,805
PENNSYLVANIA POWER AND LIGHT Residential (RS)	206,429	2,839,302	674,736	4.59	3,097,038	-2,890,609	-257,736
Residential (RH)	65,457	4,468,587	69,486		318,940	- 253,453	4,149,647
Residential (SGS, AL & CS)	1,518	118,566	232		1,065	- 453	117,501

### CATEGORY III INDICATORS OF POTENTIAL PRICING IMPROVEMENT

Recall that customers in category III are assumed to have decided, on information cost grounds, to be marginal rather than average price sensitive; it is further assumed that they do not, or do not have the opportunity to, distinguish between offpeak and peak consumption. (The latter constraint might be assumed to arise institutionally.) This set of assumptions is, as we have argued above, probably most germane to the situation of large residential users; not because it is not potentially relevant to large commercial and industrial users, but because these latter customers typically know their load curves, so that the assumption of unwillingness to differentiate between offpeak and peak consumption seems artificial.

A major difficulty surrounds the estimates of this section. For example, no company with which we are familiar knows the load curve of tailblock residential customers, i.e., those residential customers whose monthly bills put them in the final consumption block. Under the circumstances, we believe that a sensible estimate of the potential benefits to be derived from further investigation of load curves by block is as follows. Make the somewhat drastic assumption that all tailblock consumption occurs during peak hours. This, we hasten to point out, is not much different from what many utility personnel suspect: that much of peak growth attributable to residential consumption has, in recent years, been in the tailblock. Then an indicator of potential improvement can be computed by estimating the benefits accruing from an upwards adjustment of the tailboock rate towards the peak prices we have computed (and which are reported in columns 6 of Tables 32 through 36). For illustrative purposes, we have chosen a variety of "inversion" which many

of the advocates of rate inversion have put forward, an inversion in which the height of the tailblock is raised to be equal to the height of the first block. Where one half of the derived upper bound is lower than the first block height we use the former figure in this calculation.

Table 43, Category III Indicators of Potential Pricing Improvement, presents the results of these estimates. In column 1 of Table 43, we have entered the fraction of residential sales assumed to be tailblock sales, .1996. We have taken the same fraction for all systems only because we were able to get data for only one system, the Potomac Electric Power Company. In column 2 of Table 43 we have compiled estimates of peak KWH sales to residential customers by system and by season; these have been computed by the procedure set out in Table 26. Column 3 of Table 43, an estimate of peak tailblock sales, is then the product of columns 1 and 2. In column 4 of Table 43 we have compiled the relevant econometric estimates of price elasticity, the Chapman et. al. long run elasticity estimates. In column 5 of Table 43, we have recorded the height of the first block of each residential rate schedule in 1972, and in column 7 of Table 43 we have recorded the tailblock rate in effect, by system and season; in column 6 we have entered our upper bound estimate of appropriate peak price, from Tables 32 through 36. Generally, but not always, the tailblock rate is lower than the upper bound estimate of peak price and the first block rate lies between the two.

Accordingly, we compute a welfare gain estimate based upon whichever price is smaller, the difference between tailblock and first block, or the difference between tailblock and upper bound prices: that welfare estimate is what we could hope to gain by raising tailblock price by the smaller differential,

assuming all tailblock consumption to be on peak. Column 10 of Table 43 is a compilation of those welfare estimates. A warning is appropriate in the interpretation of these figure the reductions in peak consumption given by the usual elasticity formula are very large, sometimes amounting to, total peak consumption. The source of this result is apparent: the application of our long run elasticity estimates to peak price changes often amounting to more than 90 percent of initial price. Accordingly, the benefit estimates are to be taken as order of magnitude estimates.

#### CATEGORY IV INDICATORS OF POTENTIAL PRICING IMPROVEMENT

Finally, recall that customers in category IV are assumed to be both marginal price responsive and to be able to distinguish, at no additional cost, between offpeak and peak consumption: this certainly would be the case for large commercial and industrial customers who already monitor their load curves, and of these there are many. Many of these customer are billed under tariffs which have block structures for both energy and demand charges, so that the customer's bill is computed from both energy and maximum demand readings. Thus, some additional procedures must be devised before proceeding to the estimation of indicators of potential pricing gain for this customer category.

#### Net Benefit Indicators for Demand Billed Accounts

The procedures we have employed above in order to derive indicators of the net benefits available from improved pricing cannot be directly applied to schedules with a demand charge component. The reason is somewhat obvious: when the consumer's bill depends in some complex way upon not only consumption but also upon maximum demand, the relationship be-

Table 43. CATEGORY III INDICATORS OF POTENTIAL PRICING IMPROVEMENT

	1	2	3	4	5	6	7	8	9	10
System Rate Schedule (Season)	Fraction of Sales Assumed in Tail-Block	Peak KWH in Season 10 <sup>3</sup> KWH	Peak Tail-Block Sales 10 <sup>3</sup> KWH	Estimate of State Average (and Marginal) Price Elasticities	1972 First Block Rate by Season \$ KWH	Upper Bound \$ KWH	1972 Tail-Block Rate by Season \$ KWH	Difference Between Tailblock Rate and Smaller of 6 or 7 \$ KWH	Fractional Price Change	Upper Bound on Efficiency Gains $\Delta K_{pk} = \frac{1}{2} \epsilon \Delta p_{pk} \frac{\Delta p}{p}$
POTOMAC ELECTRIC POWER COMPANY Residential June-September October-January February-May	.1996 .1996 .1996	647,588 365,872 362,110	129,258 73,028 72,277 Σ 274,563	-1.22 -1.22 -1.22	.0375 .0375 .0375	.0796 .0796 .0796	.0205 .0135 .0135	.0170 .0240 .0240	-.5862 -.9412 -.9412	785,755 1,006,265 995,917 Σ 2,787,926
COMMONWEALTH EDISON COMPANY Large Residential June-September October-January February-May	.1720 .1720 .1720	2,383,353 1,290,684 2,155,833	409,937 393,998 370,803 Σ 1,174,738	-1.21 -1.21 -1.21	.0386 .0386 .0386	.0578 .0578 .0578	.0226 .0226 .0226	.0160 .0160 .0160	-.5230 -.5230 -.5230	2,075,320 1,994,628 1,877,202 Σ 5,947,150
DUKE POWER COMPANY Residential (R) July-October November-February March-June	.1996 .1996 .1996	279,346 270,234 225,059	55,757 53,939 44,922 Σ 154,618	-1.18 -1.18 -1.18	.0390 .0390 .0390	.0680 .0635 .0653	.0140 .0140 .0140	.0250 .0250 .0250	-.9434 -.9434 -.9434	775,852 75750,557 625,086 Σ 2,151,495
Residential (RA) July-October November-February March-June	.1996 .1996 .1996	578,645 559,769 466,193	115,498 111,730 93,052 Σ 320,280	-1.18 -1.18 -1.18	.0400 .0400 .0400	.0270 .0266 .0272	.0100 .0100 .0100	.0170 .0166 .0172	-.919 -.907 -.925	1,064,593 992,497 886,534 Σ 2,943,624
Residential (RW) July-October November-February March-June	.1996 .1996 .1996	1,010,966 977,988 814,499	201,789 195,206 162,574 Σ 559,569 Σ 1,034,467	-1.18 -1.18 -1.18	.0390 .0390 .0390	.0409 .0401 .0413	.0140 .0140 .0140	.0250 .0250 .0250	-.9434 -.9434 -.9434	2,806,684 2,715,122 2,261,242 Σ 7,783,048 Σ 12,878,167
Total All Residential										
NEW YORK STATE ELECTRIC AND GAS Residential November-February March-June July-October	.1996 .1996 .1996	574,163 471,407 497,435	114,603 94,093 99,288 Σ 307,984	-1.24 -1.24 -1.24	.0501 .0501 .0501	.0659 .0655 .0655	.0164 .0164 .0164	.0337 .0337 .0337	-1.0135 -1.0135 -1.0135	2,426,798 1,992,485 2,102,558 Σ 6,521,841
PENNSYLVANIA POWER AND LIGHT Residential November-February March-June July-October	.1996 .1996 .1996	724,801 568,600 582,447	144,670 113,493 116,256 Σ 374,419	-1.22 -1.22 -1.22	.0500 .0500 .0500	.0741 .0762 .0624	.0130 .0130 .0130	.0370 .0370 .0370	-1.175 -1.175 -1.175	3,822,236 2,998,528 3,071,526 Σ 9,892,290

tween perceived price and average price is somewhat more elusive. For, with few exceptions, demand charges are based upon noncoincident demand--upon the customer's maximum demand whenever that maximum demand may occur, and not upon coincident demand (the customer's demand at the time of the system peak). Our route around this dilemma is, and must be, different for the different utilities studies, largely because the nature of the data we have been able to assemble varies from company to company; valuable information would be needlessly sacrificed with a uniform methodology.

We are encouraged by the comparability of results between systems. The magnitude of the benefit measure indicator does not seem to vary widely between systems.

There are three kinds of data upon which an appraisal of the performance of demand billed rate structures can be based.

(1) From some systems we have been able to obtain data which summarize, on a monthly basis, total KWH and total KW for demand billed accounts: for each rate schedule served under a tariff with both demand and energy charges, we therefore have, on a monthly basis, total KWH, total KW, and, typically the number of bills sent. (2) For one system we have been able to obtain something very unusual: for Commonwealth Edison of Illinois we have, for a large sample of major industrial users, individual customer load curves on an hourly integrated demand basis for the whole of one week in August. Since industrial loads exhibit relatively little seasonal variation, this is valuable information. (3) For most systems, we must work from our rough constructed load curves by customer class for each season.

Such is the variation in data availability across our sample. We turn to a more explicit description of methodologies employed in each case, of checks on the adequacy of assumption and approximations, and finally to a discussion of the results. A reminder of our objective: our guiding question how well does the existing pattern of demand charges and energy charges approximate cost at peak? Of interest is not only the absolute deviation of perceived price from (our best estimate of) cost at peak, but also the importance of that derivation--a measure of benefits to be had from narrowing the discrepancy. Because methods for treating the demand billed accounts must necessarily differ between systems, whereas the methods for computing indicators of potential pricing improvement are identical, we reserve our discussion of those indicators until after the various methodologies have been discussed.

Imputation of a Mean Demand Bill Where Aggregate Demand and Energy Data are Available--Suppose we have, as we do for the Potomac Electric Power Company, data on the total KWH, total KW and number of bills, for each demand billed account, by month for 1972. Total KWH means the sum of the KWH for which customers in each demand billed customer class are billed each month; total KW means the sum of customer maximum demands for the corresponding customer class and month. The data are compiled in Table 44. A representative bill may then be imputed as follows: take the per customer average KWH and KW, and, using the rate schedule, price out the bi

Imputation of Mean Demand Bill Where Sample Data on Individual Demand-Billed Customer's is Available--Table 45, Load Curve for a Single Industrial Customer, Commonwealth Edison

Table 44. POTOMAC ELECTRIC POWER COMPANY,  
DEMAND BILLED ACCOUNTS FOR DISTRICT OF COLUMBIA,  
SELECTED MONTHS OF 1972

Rate Schedule	Month	Total KWH	Total KW	Number of Bills
Commercial	January	204,825,718	496,079.4	5,241
	April	193,396,901	500,531.7	5,329
	August	298,741,659	751,304.0	5,391
Industrial	January	118,316,350	280,948.6	129
	April	113,582,130	280,038.4	130
	August	181,845,708	395,610.2	131

Company, is included to show the type of data upon which this section builds, and to emphasize what we have said before-- that it would cost almost nothing for many systems to begin billing in a time-dependent way, since they necessarily know the load curves of their major industrial customers. By examining the hourly-integrated load figures, we can find the hour and the day, during the week for which we have this information, of the individual customer's noncoincident peak. Thus, for the customer occupying premise 47044, the peak came at 8 p.m. of August 16. We have the size of this customer's noncoincident peak-- 21,816 KW--and, from Table 45, this customer's energy consumption for the week. By multiplying that latter figure by four, we obtain an estimate of the customer's monthly consumption. Thus we have, for each individual industrial premise in the sample, an estimate of energy taken and demand. The calculation of the actual energy and demand bills paid by the individual customers is then a simple matter of looking at the relevant rate schedule and pricing out the particular customer's energy and demand charges. (This amounts to evaluating the algebraic expressions in the row 4, column 3 entry of Table 27.) In summary,

Table 45. LOAD CURVE FOR A SINGLE INDUSTRIAL CUSTOMER,  
COMMONWEALTH EDISON COMPANY, 1972  
(Hourly Integrated Demand)

Hour Ending	Aug 13	Aug 14	Aug 15	Aug 16	Aug 17	Aug 18	Aug 19
1 AM	702	14,094	9,882	9,936	6,426	9,666	2,754
2 AM	702	18,090	15,552	10,962	13,878	18,198	2,430
3 AM	756	11,556	16,362	11,448	9,666	12,420	972
4 AM	702	9,990	12,042	5,670	7,992	9,126	972
5 AM	702	18,684	15,714	12,690	16,524	17,442	864
6 AM	702	9,666	16,578	13,176	12,096	12,744	918
7 AM	702	10,692	11,826	11,340	5,076	16,956	918
8 AM	702	16,686	20,682	12,312	17,280	12,204	1,080
9 AM	756	16,470	16,578	11,664	21,114	7,506	1,026
10 AM	810	8,316	13,878	18,900	13,176	9,612	1,134
11 AM	865	19,872	13,716	17,496	5,616	7,830	1,404
12 AM	756	19,440	16,794	14,742	5,616	8,262	1,134
1 PM	648	13,824	16,470	19,008	5,022	5,454	918
2 PM	702	19,278	17,658	16,254	6,102	9,180	918
3 PM	702	18,522	16,632	11,340	6,750	6,048	918
4 PM	648	9,990	15,822	12,852	5,238	2,970	810
5 PM	648	15,822	13,122	17,334	12,906	2,322	756
6 PM	648	18,954	10,692	9,072	19,454	2,538	702
7 PM	648	12,582	11,880	16,092	17,766	3,240	756
8 PM	648	13,338	14,256	21,816	6,318	3,672	756
9 PM	702	18,630	20,250	14,688	5,130	3,240	810
10 PM	1,026	17,064	15,498	18,630	5,022	3,078	756
11 PM	1,836	19,656	20,466	20,358	3,726	2,646	756
12 PM	3,240	17,766	16,200	12,042	3,780	2,322	702
Total	20,953	368,982	368,550	339,822	231,714	188,676	25,164

for this case in which we have obtained individual customer data, we can compute energy and demand charges for each customer.

Imputation of a Mean Demand Bill Where Only Federal Power Commission Data are Available--Finally, in the case where all we have to go on are the reports all large systems must file with the Federal Power Commission (FPC Forms 1 and 12), a representative bill for demand billed schedules may be constructed as follows. First, recall that we have imputed (in the course of our reconstruction of cost structures) customer class load curves subject to various assumptions. We may, by dividing the individual rate schedule contribution to the system peak by the average number of customers and by the number of hours during the system peak, derive an estimate of individual customer demand. Similarly, an average energy per customer figure can be derived. Taking the resulting energy and demand combination as our representative bill for each rate structure, we may price out this mean bill--again, this amounts to evaluating the algebraic expression in the row 4, column 3 entry of Table 27--and proceed.

These representative bills have been constructed as guides to what might be called "perceived" prices at peak. The central fact about them is that, with few exceptions, all demand charges are based upon noncoincident demand--upon the customer's maximum demand, whenever it occurs. This is in principle unrelated to imposed capacity cost, and only makes sense to the extent that individual customer and system peak demand coincide. Do they? The question can only be answered by sample data on individual large use load curves. But the only such sample we have seen, the Commonwealth Edison data in Table 45 above, is not supportive of this inference. Another

rationale for noncoincident demand billing is, of course, that if industrial demand is approximately flat then it matters where billing demand is measured, since maximum noncoincident and coincident peak demands necessarily coincide.

How then to move from these representative bills to our benefit assessments? The crucial comparison is, of course, between perceived price at system peak and our reconstruction of cost at system peak on a rate schedule basis. The cost estimate has already been done, and amounts to our upper block column of Tables 33 through 37. The perceived price estimate remains to be computed. First, recall that in terms of our customer typology, customers are here assumed to be both marginal price responsive and time differentiating, i.e., of type IV. Thus the price we want is the perceived marginal price of a peak KWH. Since the rate schedules we are considering in this section are demand-billed, the marginal price must be the sum of an energy and a demand component. For the energy component, the obvious candidate is the actual marginal energy charge corresponding to the mean bill for each rate schedule--in effect, the height of the energy block in which the mean bill sits. For the demand charge, things are not so clear cut, for here the charge is levied upon a noncoincident maximum demand basis. We therefore assume, in constructing a measure of the perceived demand charge, that customers subject to a noncoincident demand charge spread that charge evenly over time: they assume that their monthly demand charge is incurred at a constant hourly rate. Summation of energy and demand components gives us, at last, the perceived peak period marginal prices compiled, for each system and each demand billed rate schedule, in column 2 of Table 1.

Given both perceived price and estimated marginal cost, the construction of new benefit indicators on a rate schedule

Table 46. INDICATORS OF POTENTIAL PRICING  
IMPROVEMENT, DEMAND-BILLED SCHEDULES

	1	2	3	4	5	6	7
System Rate Schedule (Season)	KWH <sub>pk</sub> 10 <sup>3</sup> KWH	Perceived KWH Marginal Price During System Peak \$ KWH	Upper Bound \$ KWH	$\Delta p_{pk}$	$\frac{\Delta p_{pk}}{p} = \frac{(4)}{(3)(2)}$	Estimate of State Average (and Marginal) Price Elasticities	Seasonal Upper Bound on Efficiency Gains = $\Delta W_{pk} =$ $\frac{1}{2} \epsilon \Delta p_{KWH} \frac{\Delta p}{p}$
<b>POTOMAC ELECTRIC POWER COMPANY</b>							
General Service (GS)							
June-September	1,268,353	.0151	.0216	.00650	.354	-1.46	2,131,621
October-January	716,594	.0145	.0250	.01050	.532	-1.46	2,919,815
February-May	709,222	.0145	.0235	.00900	.474	-1.46	2,207,172
Large Power Service							
June-September	279,009	.00859	.0178	.00921	.698	-1.93	1,730,847
October-January	279,009	.00844	.0212	.01276	.861	-1.93	2,957,993
February-May	279,009	.00844	.0210	.01166	.817	-1.93	2,553,178
	$\Sigma$ 3,531,196						$\Sigma$ 14,500,626
<b>COMMONWEALTH EDISON COMPANY</b>							
Small Commercial and Industrial							
June-September	2,276,368	.0148	.0280	.0132	.617	-1.48	13,718,828
October-January	2,222,243	.0148	.0280	.0132	.617	-1.48	13,392,638
February-May	2,059,061	.0148	.0280	.0132	.617	-1.48	12,409,199
Large Commercial and Industrial							
June-September <sup>b</sup>	1,990,614	.0094	.0228	.0135	.841	-1.87	21,422,454
October-January <sup>b</sup>	1,943,283	.0094	.0228	.0135	.841	-1.87	20,913,235
February-May <sup>b</sup>	1,800,586	.0094	.0228	.0135	.841	-1.87	19,382,867
	$\Sigma$ 12,292,155						$\Sigma$ 101,239,221
<b>DUKE POWER COMPANY</b>							
General Service (G)							
July-October	891,246	.0121	.0205	.0084	.515	-1.13	2,178,306
November-February	862,173	.0121	.0202	.0081	.502	-1.13	1,980,697
March-June	718,045	.0121	.0208	.0087	.529	-1.13	1,867,074
General Service (GA)							
July-October	548,715	.0081	.0143	.0062	.554	-1.13	1,064,835
November-February	530,816	.0081	.0142	.0061	.547	-1.13	1,000,682
March-June	442,080	.0081	.0146	.0065	.573	-1.13	930,258
General Service (I)							
July-October	1,402,182	.0061	.0135	.0074	.755	-1.65	6,462,854
November-February	1,402,182	.0061	.0134	.0073	.749	-1.65	6,324,853
March-June	1,402,182	.0061	.0138	.0077	.774	-1.65	6,894,097
	$\Sigma$ 8,199,621						$\Sigma$ 28,703,656

<sup>a</sup> Circled numbers are column numbers; uncircled number is the digit 2.

<sup>b</sup> Data are averages from calculations from a sample of premises.

Table 46 (Continued). INDICATORS OF POTENTIAL PRICING IMPROVEMENT, DEMAND-BILLED SCHEDULES

System Rate Schedule (Season)	1 KWH <sub>pk</sub> 10 <sup>3</sup> KWH	2 Perceived KWH Marginal Price During System Peak \$ KWH	3 Upper Bound \$ KWH	4 $\Delta p_{pk}$	5 $\frac{\Delta p_{pk}}{p} = \frac{(4)}{(3)(2)} \cdot \frac{1}{2\alpha}$	6 Estimate of State Average (and Marginal) Price Elasticities	7 Seasonal Upper Bound on Efficiency Gains = $\Delta W_{pk} =$ $\frac{1}{2} \epsilon \Delta p_{pk} \frac{\Delta p}{p}$
NEW YORK STATE ELECTRIC AND GAS							
General Service (PSC108SC2)							
November-February	86,342	.0121	.0227	.0106	.6092	-1.65	459,969
March-June	71,023	.0121	.0229	.0108	.6171	-1.65	390,497
July-October	74,944	.0121	.0229	.0106	.6092	-1.65	399,248
General Service (PSC113SC2)							
November-February	147,458	.0240	.0333	.0093	.3246	-1.65	367,232
March-June	120,931	.0240	.0333	.0093	.3246	-1.65	301,167
July-October	127,991	.0240	.0333	.0093	.3246	-1.65	318,751
Large Light and Power (PSC113SC3)							
November-February	191,910	.0149	.0178	.0029	.1774	-1.89	93,271
March-June	191,910	.0149	.0181	.0032	.1939	-1.89	112,491
July-October	191,910	.0149	.0180	.0031	.1884	-1.89	105,884
Primary Light and Power (PSC108SC3)							
November-February	33,310	.0073	.0176	.0103	.8273	-1.89	268,145
March-June	33,310	.0073	.0179	.0106	.8413	-1.89	280,625
July-October	33,310	.0073	.0178	.0105	.8367	-1.89	276,457
<b>Σ 1,304,349</b>							<b>Σ 3,373,737</b>
PENNSYLVANIA POWER AND LIGHT COMPANY							
General Service (SGS)							
November-February	116,606	.0328	.0597	.0269	.582	-1.46	1,332,126
March-June	91,447	.0328	.0617	.0289	.612	-1.46	1,178,758
July-October	93,709	.0328	.0489	.0161	.394	-1.46	433,762
Large General Service (LP-3)							
November-February	439,437	.0121	.0219	.0098	.577	-1.46	1,813,207
March-June	345,134	.0121	.0227	.0108	.621	-1.46	1,689,087
July-October	353,557	.0121	.0195	.0074	.468	-1.46	893,482
Large General Service (LP)							
November-February	44,302	.0102	.0219	.0117	.729	-1.93	364,635
March-June	44,302	.0102	.0225	.0123	.752	-1.93	395,429
July-October	44,302	.0102	.0196	.0094	.631	-1.93	253,573
Primary General Service (LP-4)							
November-February	160,438	.0085	.0210	.0125	.848	-1.93	1,641,113
March-June	160,438	.0085	.0216	.0131	.870	-1.93	1,764,504
July-October	160,438	.0085	.0187	.0102	.750	-1.93	1,184,388
High-Tension General Service (LP-5)							
November-February	81,890	.0066	.0211	.0145	1.047	-1.93	1,199,694
March-June	81,890	.0066	.0217	.0151	1.067	-1.93	1,273,202
July-October	81,890	.0066	.0188	.0122	.961	-1.93	926,486
High-Tension General Service (LP-6)							
November-February	188,779	.0057	.0209	.0152	1.143	-1.93	3,164,962
March-June	188,779	.0057	.0215	.0158	1.162	-1.93	3,344,583
July-October	188,779	.0057	.0186	.0129	1.062	-1.93	2,495,703
<b>Σ 2,866,077</b>							<b>Σ 25,348,694</b>

basis is straightforward, and is carried out in Table 46, Indicators of Potential Pricing Improvement, Demand-Billed Schedules. Again, as in the case of the Category III benefit estimates, a warning is appropriate in the interpretation of these figures. The reductions in peak consumption given by the usual elasticity formula are very large, sometimes amounting to total peak consumption. Here, as before, the source of this result is apparent: the application of long run elasticities to peak price changes often amounting to more than 90 percent of perceived price. Accordingly, the benefit estimates are to be taken as order of magnitude estimates.

## SECTION V

### REFERENCES

1. Anderson, K., Industrial Energy Demand (Rand Corporation, 1971).
2. Baumol, W., and Bradford, D., "Optimal Departures from Marginal Cost Pricing," American Economic Review (June, 1970).
3. Chapman, L.D., et. al., "Electricity Demand in the United States: An Econometric Analysis," Oak Ridge National Laboratory, Preliminary, June 1973.
4. Federal Power Commission, The 1970 National Power Survey (Washington, D.C.: U.S. Government Printing Office, 1971), Volume I, p. I-1-11.
5. Fisher, F.M., and Kaysen, C., A Study in Econometrics: The Demand for Electricity in the United States (Amsterdam: North-Holland Publishing Company, 1962).
6. Halvorsen, R., "Residential Electricity: Demand and Supply," Environmental Systems Program, Harvard University, preliminary mimeograph, 1971.
7. Smith, V.K., et. al., "Econometric Estimation of Electricity Demand," mimeograph, 1973.
8. Wilson, J.W., "Residential Demand for Electricity," Quarterly Review of Economics and Business (Spring, 1971).

<b>BIBLIOGRAPHIC DATA SHEET</b>	<b>1. Report No.</b> EPA-600/5-74-033	<b>2</b>	<b>3. Recipient's Accession No.</b>
<b>4. Title and Subtitle</b> The Economic and Environmental Benefits from Improving Electrical Rate Structures			<b>5. Report Date</b> November 1974
<b>7. Author(s)</b> Dr. Mark Sharefkin			<b>6.</b>
<b>9. Performing Organization Name and Address</b> Jack Faucett Associates 5454 Wisconsin Avenue Chevy Chase, Maryland 20015			<b>8. Performing Organization Report No.</b> JACKFAU-101-74
<b>12. Sponsoring Organization Name and Address</b> Environmental Protection Agency Implementation Research Division Washington, D.C. 20460			<b>10. Project/Task/Work Unit No.</b> PE 1HA093 21AQT-03
			<b>11. Contract/Grant No.</b> 68-01-1850
			<b>13. Type of Report &amp; Period Covered</b> Final Report
<b>15. Supplementary Notes</b>			<b>14.</b>
<b>16. Abstracts</b> Quantitative estimates of the internal cost savings to be derived from changes in the pricing of electric power are devised and evaluated. The econometric literature on electricity demand is surveyed, and elasticity values are selected which are parameters for the overall benefit measures. A method for using reported utility data to estimate the cost of delivered power--at the system peak and off the system, and for each customer class--is devised. Data on five electric utilities is used to make estimates of the potential benefits from improvements in the pricing of electric power, for each customer class in each system. The estimated potential benefits are sufficiently large to merit load curve studies by block for residential customers. Such studies are necessary preliminaries to a definitive assessment of the proposals for so called inversion.			
<b>17. Key Words and Document Analysis. 17a. Descriptors</b>  Electric Power Rate Structure Environmental Benefits Load Curves Peak-Load Pricing			
<b>17b. Identifiers/Open-Ended Terms</b>			
<b>17c. COSATI Field/Group</b>			
<b>18. Availability Statement</b>		<b>19. Security Class (This Report)</b>	<b>21. No. of Pages</b> 187
		<b>20. Security Class (This Page)</b>	<b>22. Price</b>